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Technical and economical analyses of combined heat and power generation from distillers grains and corn stover in ethanol plants

Lijun Wang [a,*], Milford A. Hanna [b], Curtis L. Weller [b], David D. Jones [b]

[a] Department of Natural Resources and Environmental Design, North Carolina A&T State University, Greensboro, NC 27411, USA
[b] Industrial Agricultural Products Center, Department of Biological Systems Engineering, University of Nebraska-Lincoln, Lincoln, NE 68583-0726, USA

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ABSTRACT

The technical and economical feasibilities of a novel integrated biomass gasification and fuel cell combined heat and power (CHP) system were analyzed for supplying heat and power in an ethanol plant from distillers grains (DG) and corn stover. In a current dry-grind plant with an annual production capacity of 189 million liters (50 million gallons) of ethanol, the energy cost for ethanol production using natural gas at a price of 6.47 US$/GJ for processing heat and commercial grid at a price of 0.062 US$/kWh for electrical power supply was 0.094 US$/liter. If the integrated CHP system using wet DG with 64.7% moisture on a wet basis at 105 US$/dry tonne and corn stover with 20% moisture at 30 US$/dry tonne as feedstock was used to supply heat and power in the ethanol plant, the energy costs for ethanol production would be 0.101 US$/liter and 0.070 US$/liter, which are 107% and 75% of the current energy cost for ethanol production, respectively. To meet the demand of processing heat and power in the ethanol plant, the integrated CHP system required 22.1 dry tonnes of corn stover with 20% moisture or 14.5 dry tonnes of DG with 64.7% moisture on a wet basis per hour, compared with the available 18.8 dry tonnes of DG per hour in the ethanol plant. High-value chemicals such as policosanols, phytosterols and free fatty acids can be extracted out of the raw DG to reduce the cost of DG as a feedstock of the integrated CHP system. The energy cost for ethanol production using the integrated CHP system with corn stover and DG as the feedstock for supplying heat and power can be reduced further by increasing ethanol production scale, decreasing the moisture content of biomass feedstock, and decreasing thermal energy to electricity output ratio of the CHP system. In terms of the energy efficiency of the integrated CHP system and the energy cost for ethanol production, the moisture content of the feedstock going into the integrated CHP should be lower than 70% on a wet basis.

1. Introduction

Ethanol production continues to expand in the United States. Approximately two-thirds of the current ethanol production capacity is based on dry-grinding technology. Nearly all of the fuel ethanol currently produced in the United States uses corn as a feedstock. For dry-grind production of each liter of ethanol, the energy content residing in the ~0.8 kg by-products of distillers grains (DG) on a dry basis is more than 20 MJ, compared to the consumption of 0.29 kWh (or ~1 MJ) electricity and 10 MJ thermal energy for ethanol processing [1]. High-value lipids such as policosanols, phytosterols and free fatty acids can be extracted from DG [2,3]. Thus, DG is a potential renewable resource of industrial feedstock for production of high-value chemicals and for supplying heat and power to an ethanol plant. Furthermore, there is usually a large amount of corn stover available around an ethanol plant, which is an alternative renewable energy resource for the ethanol plant.

A combined heat and power (CHP) system is a decentralized production system where the heat and power production occurs close to the areas of their consumption. The implementation of CHP technology is capable of providing highly efficient and environmentally-friendly electricity and heat. Furthermore, unlike conventional power stations, CHP systems produce electricity locally and, thus, minimize distribution losses [4]. There are three main systems for combined heat and power generation from biomass: (1) biomass direct combustion connected with steam generation and steam turbines, (2) biomass gasification connected with gas engines or gas turbines, and (3) biomass gasification connected with fuel cells. Direct co-firing of biomass in existing combustors has been used for CHP generation [5]. However, co-firing reduces the thermal efficiency of the existing power plants. The energy efficiency of current biomass combustion technologies with steam generation and steam turbines is only 15–18% [6]. Due to concern about plugging of a coal feed system, biomass feed usually is limited to 5–10% of the total feedstock [7,8].

Gasification technology has been investigated to effectively and economically convert low-value solid biomass to a uniform gas-

* Corresponding author. Tel.: +1 336 334 7787; fax: +1 336 334 7270.
E-mail address: lwang@ncat.edu (L. Wang).

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eous mixture (known as syngas) consisting mainly of CO, H_2, CO_2 and traces of CH_4. The syngas can be used to produce heat and power in a combustor, gas turbine, gas engine or fuel cell depending on syngas quality. Low heat-value syngas from air gasification of biomass can be used in a combustor [9]. Compared to direct biomass combustion, syngas from biomass gasification can increase the biobased fuel percentage used in existing combustors. Biomass gasification can reduce the potential of ash-related problems in the direct biomass combustion because the gasification temperature is lower than combustion temperature and clean syngas is supplied to the combustor. A gasification process can use a variety of biomass feedstocks with large variations in their properties such as moisture content and particle size. However, if syngas is combusted directly to generate steam for power generation via a steam turbine, the electricity efficiency is limited by the theoretical limit of a steam turbine.

High-quality syngas can be fed directly to gas engines [10,11], gas turbines [12–14], or fuel cells [15] for power generation. Compared to a combustor, a gas engine, gas turbine or fuel cell requires syngas with a high heating value and almost free of tar and dust [12,13]. Syngas usually is cooled down to increase the energy density for its use in a gas engine, which decreases the energy efficiency. Gas turbines can transform hot syngas to mechanical energy and, thus, increase the energy efficiency of conversion. A biomass integrated gasification combined cycle (BIGCC) involves combustion of the hot syngas from a gasifier in a gas turbine to generate electricity in a topping cycle. The hot exhaust gas from the turbine is used to generate stream for generating additional electricity in a steam turbine in bottom cycle or for supplying processing heat. The BIGCC is a promising technology for large-scale combined heat and power generation from biomass due to its high flexibility in biomass feedstocks and high electrical efficiency [13]. Fuel cells are considered to be significantly innovative and recently have become available technology for energy conversion since they are environmentally-friendly and highly efficient at generating electricity and heat from hydrogen or hydrogen-rich syngas [15,16]. A biomass gasification/fuel cell CHP system has overall high energy efficiency and low pollutant emission, even in small-scale biomass gasification plants and under partial load operation [6]. As the direct energy source of a fuel cell is hydrogen, biomass must be converted to hydrogen or hydrogen-rich syngas before feeding it to the fuel cell.

The objective of this research was to analyze the technical and economical feasibilities of a novel biomass gasification and fuel cell CHP system for supplying heat and power from DG and corn stover in ethanol plants. Specifically, the effects of ethanol plant production scale, price of energy feedstock, moisture content of feedstock and thermal energy to electricity output ratio of the integrated CHP system on energy cost for ethanol production and the performance of the integrated system were analyzed.

2. Mathematical model

2.1. Description of an integrated biomass gasification and fuel cell CHP system

A novel integrated biomass fluidized bed gasifier and fuel cell CHP system, as shown in Figs. 1 and 2, is being developed for generating heat and power from renewable resources such as DG and corn stover in the ethanol industry. In this system, wet biomass particles are dried by the depleted hot flue gas from the burner in a biomass drier. The dried biomass is then converted into syngas in a steam fluidized bed gasifier, which is heated externally by a high-temperature medium from a depleted syngas burner. The hot syngas from the gasifier is reformed and cleaned to hydrogen-rich syngas in a hot syngas conditioner. The hydrogen-rich syngas and air are then introduced into a solid oxide fuel cell to generate electricity. The remaining high-temperature depleted syngas and air from the fuel cell stack flow into the burner to provide heat for the gasifier and drier, and generate steam in a boiler as a gasifying agent for the gasifier and a thermal energy source for the ethanol plant. Depending on electricity and thermal energy demands, part of the primary syngas exiting the gasifier is fed directly into the burner for more heat generation.

2.2. Estimation of mass and energy flow of biomass through the CHP system

2.2.1. Biomass drier

The CHP system started with drying of biomass feedstock using waste heat generated by the CHP system. The mass balance in a biomass dryer was

$$F_f = F_{df} + F_{wf} \tag{1}$$

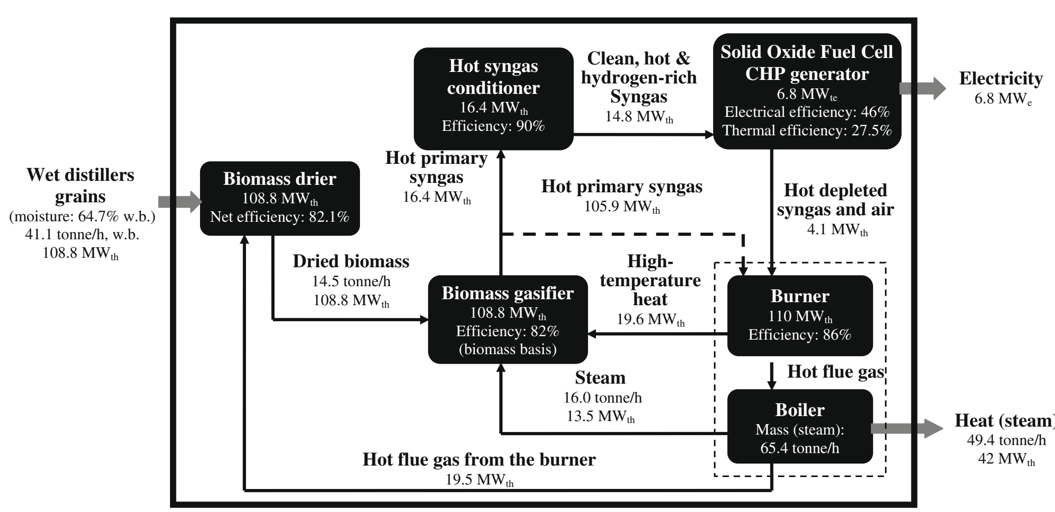

Fig. 1. Mass and energy flows of wet distiller gains through an integrated fluidized bed gasifier and fuel cell CHP system for heat and power supply in a dry-grind ethanol plant with an annual production capacity of 189 million liters of ethanol.

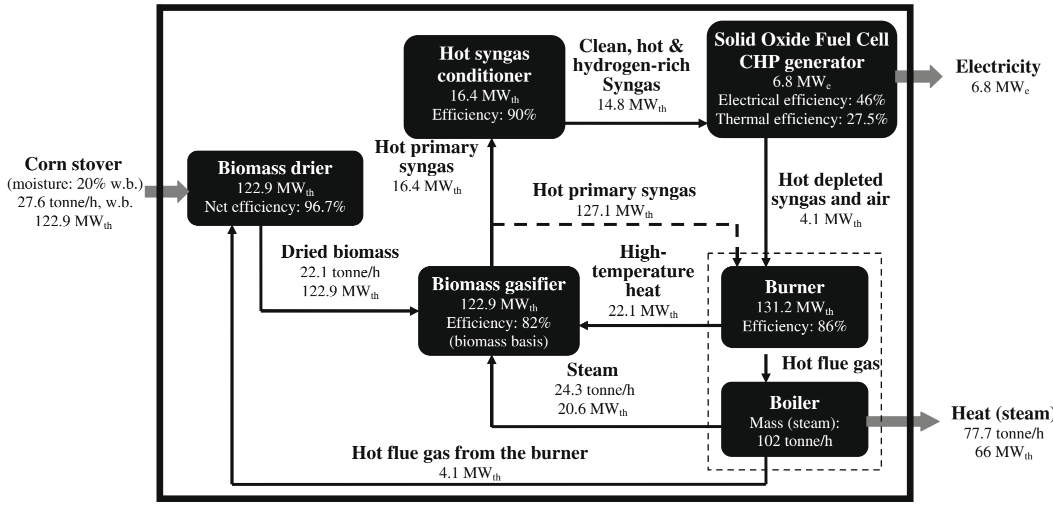

Fig. 2. Mass and energy flows of corn stover through an integrated fluidized bed gasifier and fuel cell CHP system for heat and power supply in a dry-grind ethanol plant with an annual production capacity of 189 million liters of ethanol.

where F_f, F_{df}, and F_{wf} are the mass flow rates of wet biomass into the drier, and dried biomass and moisture out of the drier (kg/h, wet basis).

The mass flow rate of moisture out of the dryer is a function of the feeding rate of the wet biomass, F_f, and its moisture content, X_w (%, wet basis), which was expressed as

$$F_{wf} = F_f X_w \tag{2}$$

Substituting Eq. (2) into Eq. (1), the mass flow rate of dried biomass out of the dryer was

$$F_{df} = F_f(1 - X_w) \tag{3}$$

During drying, external heat is required to evaporate the moisture out of the biomass. The consumption rate of energy in the drier to remove the feedstock moisture, E_d (MJ/h) can be determined by the heat transfer efficiency of the drier, η'_d, the mass rate of the moisture to be removed and the latent heat of moisture evaporation, ΔH_v (MJ/kg), which was given by

$$E_d \eta'_d = F_{wf} \Delta H_v \tag{4}$$

or

$$E_d = \frac{F_{wf} \Delta H_v}{\eta'_d} \tag{5}$$

Since the heat required to dry wet biomass was supplied externally, there was no change of the energy stored in the biomass through the dryer. The energy flux rate of biomass feedstock through the dryer, E_f (MJ/h), was calculated as a function of the mass flow rate of dry matter of the biomass and the heating value of the biomass, ΔH_f (MJ/kg, dry basis), which was expressed as

$$E_f = F_{df} \Delta H_f \tag{6}$$

Thus, the net thermal efficiency of the biomass drier was

$$\eta_d = \frac{E_f - E_d}{E_f} \times 100\% \tag{7}$$

2.2.2. Biomass gasifier

Biomass gasification involves endothermic, heterogeneous, reversible and reduction reactions [17]. Steam was used as the oxidant agent to gasify biomass. The mass flow rate of steam into the gasifier was determined by the stoichiometric formula of the steam biomass gasification reaction for a given biomass feedstock, which is given by

$$F_{gs} = F_{df} R \tag{8}$$

R in the above equation is the mass ratio between steam and biomass feedstock, which is usually between 1 and 2 for steam gasification of biomass [18,19]. If the average compositions of biomass and coal are $CH_{1.4}O_{0.6}$ and $CH_{0.95}O_{0.2}$ [20], the general formulas for steam gasification of biomass and coal are:

$$CH_{1.4}O_{0.6} + 1.4H_2O \rightarrow CO_2 + 2.1H_2 \tag{9}$$

$$CH_{0.95}O_{0.2} + 1.8H_2O \rightarrow CO_2 + 2.275H_2 \tag{10}$$

According to the above formulas, the values of R (mass ratio) for steam gasification of biomass and coal are 1.1 and 2, respectively, which were used in this research. The energy flux rate of steam into the gasifier is a function of the mass flow rate of steam and its enthalpy, which was expressed as

$$E_{gs} = F_{gs} \Delta H_s \tag{11}$$

where ΔH_s was the enthalpy of steam into the gasifier (MJ/kg).

The energy for heating the biomass feedstock and endothermic reactions during biomass gasification was supplied by an external syngas burner. The energy consumption rate by the gasifier was calculated as a percentage of the total energy content residing in the dried biomass feedstock, η_g, which was given by

$$E_g = \eta_g E_f \tag{12}$$

The energy loss for heating fuel and chemical reactions for a gasification process at an equilibrium condition was found to be 18% [20], which was used in this research.

Since the heat required for gasification was supplied externally, the total energy flux of the product syngas was the sum of the energy fluxes of dried biomass and steam into the gasifier, which was expressed as

$$E_p = E_f + E_{gs} \tag{13}$$

2.2.3. Fuel cell CHP generator

Gas turbines, gas or steam engines and fuel cells may be used for combined heat and power generation. A fuel cell uses H_2 and O_2 to produce electricity and the by-product of heat in the presence of an electrically conductive electrolyte material. Although H_2 is the only electrochemically active fuel in the fuel cell, CH_4 and CO in the syngas can be converted into H_2 using water-reforming and water–gas shift reactions [21]. The current cost of a solid oxide fuel cell is US$ 400/kWe, which is comparable to the costs of gas turbines and internal engines [22]. The electricity generation efficiency of fuel cells at ~45% [23] is usually higher than that of turbines and engines at ~35% [24]. Considering the increased energy efficiency, reduced emission and flexibility in varying production scale, fuel cell CHP systems hold a promising market potential in CHP generation [21]. A solid oxide fuel cell was used to generate electricity from clean, hot and hydrogen-rich syngas at an electricity efficiency of η_{fce} in this research The energy flux rate of hydrogen-rich syngas into the fuel cell to meet the electricity demand at E_e (MW_e), was thus given by

$$E_{fci} = \frac{E_e}{\eta_{fce}} \tag{14}$$

By-product heat was generated in the high-temperature fuel cell at a thermal efficiency of η_{fct}. This amount of heat can be recovered through the syngas burner. The thermal energy flux rate of the depleted syngas and air out of the fuel cell was determined by

$$E_{fct} = E_{fci}\eta_{fct} \tag{15}$$

A field test showed that the EDB/ELSAM 100 kW SOFC–CHP system developed by Westinghouse produced 109 kW_e net AC to the utility grid at 46% electrical efficiency and 65 kW_{th} at 27.5% of thermal efficiency to the district heating system [23]. Therefore, the electrical and thermal efficiencies of the fuel cell were set at 46% and 27.5% in this simulation, respectively.

2.2.4. Syngas conditioner

As shown in Figs. 1 and 2, depending on electricity demand, the syngas supplied into the fuel cell for electricity generation was cleaned through a hot syngas conditioner. The remaining part of the syngas was directly fed into the syngas burner for supplying gasification reaction heat and processing heat in the ethanol plant. The thermal energy flux rate of primary syngas into the hot syngas conditioner for the electricity generation was

$$E_c = \frac{E_{fci}}{\eta_c} \tag{16}$$

where η_c was the energy efficiency of the hot syngas conditioner.

2.2.5. Syngas burner and energy efficiency of the whole CHP system

The total thermal energy flux rate into the syngas burner was the energy flux rates of the primary syngas from the gasifier, minus the primary syngas into the hot syngas conditioner and plus the depleted syngas and air from the fuel cell, which was expressed as

$$E_{bi} = E_p - E_c + E_{fct} \tag{17}$$

The total energy flux rate out of the syngas burner was determined as

$$E_{bo} = E_{bi}\eta_b \tag{18}$$

where η_b was the heat transfer efficiency of the burner.

The energy generated by the burner was used to provide heat for biomass drying, E_d, and biomass gasification, E_g, generate steam for biomass gasification, E_{gs} and provide processing heat in the ethanol plant, E_{th}. There was

$$E_{bo} = E_d + E_g + E_{gs} + E_{th} \tag{19}$$

The required amount of biomass feedstock was determined by substituting E_{bo}, E_d, E_g, E_{gs} and E_{th} into Eq. (19), which was expressed as:

$$F_f = \frac{F_{ps}\Delta H_s + E_e(1-\eta_{fct})\eta_b/(\eta_{fce}\eta_c)}{(1-X_w)\Delta H_f\eta_b - (1-X_w)R\Delta H_s(1-\eta_b) - (1-X_w)\Delta H_f(1-\eta_g) - X_w\Delta H_v/\eta'_d} \tag{20}$$

The electricity and thermal energy efficiencies of the integrated CHP system were calculated as

$$\eta_e = \frac{E_e}{E_f} \times 100\% \text{ and} \tag{21}$$

$$\eta_{th} = \frac{E_{th}}{E_f} \times 100\% \tag{22}$$

2.3. Economic analysis of the CHP system

The capital cost of the integrated CHP system consists of equipment cost and installation cost. The equipment cost of each component of the integrated CHP system was a function of its size, which was calculated by [25]

$$\frac{\text{Cost}}{\text{Cost}_{\text{ref}}} = \left(\frac{\text{Size}}{\text{Size}_{\text{ref}}}\right)^n \tag{23}$$

where Cost_{ref} is reference cost at a reference unit size of Size_{ref}, and n is cost scaling factor. The cost scaling factors were usually between 0.6 and 0.8 [25].

There were five main units of the integrated biomass gasification and fuel cell CHP system, which were: (1) biomass pretreatment unit, (2) biomass gasifier, (3) syngas cleaning unit, (4) fuel cell for electricity generation, and (5) boiler for steam generation. The capital costs of each component were estimated from its basic cost at a reference scale and its scaling factor given in Table 1 using Eq. (23). The installation costs for buildings, instrument and controls, piping system, electronics and installation labor were calculated as 1.5%, 5%, 4%, 7%, and 10%, respectively, of total equipment cost of the CHP system adapted from the literature [25]. The total

Table 1
Reference capital costs and cost scaling factors of each component of the integrated CHP system.

	Reference unit scale	Reference unit cost (M US$)	Cost scaling factor	Reference
Feedstock pretreatment system				
Converyers (MW_{th})	69.54	0.33	0.8	[25]
Grinding (MW_{th})	69.54	0.43	0.6	[25]
Storage (MW_{th})	69.54	1.05	0.65	[25]
Dryer (MW_{th})	69.54	7.71	0.8	[25]
Gasifier and feeder (MW_{th})	400	13	0.7	[25]
Syngas cleaning				
Cyclones (MW_{th})	69.5	2.57	0.7	[25]
Syngas compressor (MW_e)	13.2	12	0.85	[25]
Hot syngas conditioner (MW_{th})	400	14.30	0.7	[25]
CHP system				
Fuel cell (MW_e)	1.00	0.4	1.0	[36]
Burner and boiler (tonne steam/h)	49.5	0.43	0.9	[22]

capital cost of the integrated CHP system was the sum of the total equipment cost and installation cost.

In order to evaluate the potential economic benefits of the integrated biomass gasification and fuel cell CHP system, the capital cost of the integrated CHP system was discounted using the annuity method [26]:

$$A = P \times \frac{i(1+i)^n}{(1+i)^n - 1} \tag{24}$$

where A is the annual capital cost, P is the present value of total capital cost, i is the interest rate or internal rate of return (%) and n is the economic life time of the plant (in year).

The operating cost included costs for feedstock, ash deposal, personnel and facility maintenance. The total feedstock cost was a function of the total amount of feedstock required by the CHP system as determined by Eq. (20) and the unit price of the feedstock. Solid energy resources such as biomass and coal usually contain ash. The mass rate of ash generated during gasification was the feeding rate of feedstock multiplied by the ash content of the feedstock. The ash should be deposed after gasification and the total cost for the ash deposal was a function of the total amount of ash generated and the unit cost for ash deposal. Since the CHP system is complex, specific personnel should be assigned to supervise the daily operation of the system. The personnel cost was included in the total operating cost. The maintenance cost of the CHP system was calculated as a percentage of the total capital cost of the CHP system.

3. Results and discussion

3.1. Model validation

Three categories of parameters: (1) heat and power demand in an ethanol plant, (2) properties and unit price of potential energy feedstocks for the CHP system, and (3) energy efficiencies of each component of the CHP system, were required in the model for the analyses of the mass and energy flows and the economics of the integrated CHP system. The values of those parameters were taken from literature, which are given in Table 2.

The simulation started with the determination of feedstock demand, and calculation of mass and energy flux through the CHP system to determine the size of each component of the CHP system using Eqs. (1)–(20). The electricity and thermal energy efficiencies of the integrated CHP system were then calculated by Eqs. (21) and (22), respectively. The capital cost of each component of the integrated CHP system at a determined scale was calculated by Eq. (23). The total capital cost of the CHP system was the sum of the capital costs of its components and its installation costs. The annual capital cost was then determined by Eq. (24). The annual feedstock cost was calculated by multiplying the required annual amount of biomass feedstock by the unit price of the feedstock given in Table 2. The total annual operating cost was the sum of the annual costs for feedstock, ash deposal, personnel and facility maintenance.

Predictions with the model were compared with the values published in literature. The initial capital cost of a 27 MWe integrated biomass gasification combined cycle (IGCC) using corn stover as its feedstock was predicted at US$ 2694/kWe, which was comparable to US$ 2750/kWe for an IGCC at the same size reported in literature [27]. The biomass feedstocks have to be handled, stored and processed prior to gasification. The capital cost of the pretreatment unit for an integrated biomass gasification and fuel cell CHP system with a loading capacity of 1000 tone of dry biomass per day was estimated at US$ 362/kWe while it was reported to be US$ 200–500/kWe at the same scale [27].

Table 2
Model parameters of ethanol plant, potential energy feedstocks, and energy efficiencies of each component of the CHP system.

Ethanol plant	Production	Annual ethanol production capacity (million liter/year)	189	–
		Annual working hours (h/year)	8000	–
		Facility life (year)	15	[26]
	DDGS	DDGS generation (kg DDGS/l ethanol)	0.8	[34]
	Heat and power demand	Electricity consumption (kWh/l ethanol)	0.29	[1]
		Thermal energy consumption (MJ/l ethanol)	10	[1]
Potential energy feedstock	Corn stover	Moisture content (%, wet basis)	20	[29]
		Ash content (%, dry basis)	5	[29]
		Heating value (MJ/kg, dry basis)	20	[29]
		Reference unit price (US$/tonne, dry basis)	30	[29]
	Wet DG	Moisture content (%, wet basis)	64.7	[33]
		Ash content (%, dry basis)	5.7	[33]
		Heating value (MJ/kg, dry basis)	27	–
		Reference unit price (US$/tonne, dry basis)	105	[35]
	Coal	Moisture content (%, wet basis)	2.52	[32]
		Ash content (%, dry basis)	10.5	[32]
		Heating value (MJ/kg, dry basis)	30	[32]
		Reference unit price (US$/tonne, dry basis)	28	[a]
	Natural gas and electricity	Higher heating value of natural gas (MJ/Nm^3)	38	[21]
		Reference unit price of natural gas(US$/GJ)	6.47	[a]
		Reference unit price of commercial electricity (US$/kWh)	0.062	[a]
	Ash deposal	Reference unit cost of ash deposal (US$/tonne)	100	[23]
Integrated CHP system	Feedstock pretreatment	Heat transfer efficiency of the drier, η'_d	0.95	[31]
		Latent heat of moisture evaporation during drying (MJ/kg)	2.5	[26]
	Gasification	The mass ratio of steam to dry biomass, R	1.1	[20] and Eq. (9)
		The mass ratio of steam to coal, R	2.0	[20] and Eq. (10)
		Energy consumption by the gasifier as percentage of the energy residing in the dried feedstock, η_g (%)	18	[20]
	CHP generation	Energy efficiency of hot syngas conditioner, η_c	0.9	[30]
		Electricity efficiency of fuel cell, η_{fce}	0.46	[23]
		Thermal efficiency of fuel cell, η_{fct}	0.275	[23]
		Burner and boiler energy efficiency, η_b	0.86	[26]

[a] Energy information administration, United States of America, online at http://tonto.eia.doe.gov.

3.2. Analyses of feasibility of an integrated CHP system for heat and power supply in ethanol plants

The analyses of mass and energy flows through the integrated CHP system were carried out for supplying heat and power in a dry-grind ethanol plant with an annual production capacity of 189 million liters (50 million gallons). The thermal energy and electricity demands in a dry-grind ethanol plant were reported to be 0.29 kWh/l and 10 MJ/l [1]. Since annual working time is 8000 h, the processing heat demand was thus 66 MW_{th} (or 77.7 tonne steam/h at the enthalpy of 3.06 MJ/kg) and the power demand was 6.8 MW_e. The dry-grind ethanol plant generates 0.8 kg of dried distillers grains (DDG) for each liter of ethanol produced [1]. The production rate of DDG was thus 18.8 tonne/h. However, if the wet DG is not dried to be sold as a by-product, the thermal energy demand can be significantly decreased. According to calculation, it consumes 24 MW_{th} of thermal energy to dry wet DG with an initial moisture content of 64.7% at a rate of 18.8 dry tonne/h. If the wet DG is not dried, the processing heat demand in the ethanol plant becomes 42 MW_{th} (or 49.4 tonne steam/h at the enthalpy of 3.06 MJ/kg) and the power demand is still 6.8 MW_e. DG, corn stover and coal were considered as potential feedstocks of the integrated gasification and fuel cell CHP system in an ethanol plant. The mass and energy fluxes of these three feedstocks through the CHP system are given in Figs. 1–3.

As shown in Fig. 1, the feeding rate of wet DG with 64.7% moisture, on a wet basis, should be 41.1 tonne/h, which corresponds to 14.5 tonne/h of DDG, to meet the 42 MW_{th} processing heat and 6.8 MW_e power demands in the ethanol plant with an annual ethanol production capacity of 189 million liters. There was 18.8 tonne/h of DDG available in the ethanol plant. Since the availability of distillers grains is more than its demand as a feedstock for the integrated CHP system, high-value lipid chemicals such as policosanols, phytosterols and fatty acids can be extracted out of the DG to reduce the cost of DG as a feedstock for the integrated CHP system [2,3]. A 108.8 MW_{th} biomass dryer and 108.8 MW_{th} biomass gasifier were required to convert wet DG into syngas. A 16.4 MW_{th} hot syngas conditioner and 6.8 MW_e fuel cell were required to generate 6.8 MW_e electricity for the ethanol plant. A 110 MW_{th} combustor was required to provide heat and steam for the gasifier, heat for the dry and processing heat for the ethanol plant. The energy flux rate of the drying medium into the dry was 19.5 MW_{th}. The net energy efficiency of the drier was thus 82.1%. That means 17.9% of the energy stored in the DG feedstock was cycled back and used to remove the moisture in the feedstock. Since the electricity output, thermal energy output and thermal energy input of the integrated CHP system were 6.8 MW_e, 42 MW_{th} and 108.8 MW_{th}, respectively, the electricity, thermal and total efficiencies of the CHP system were 6.3%, 38.6%, and 44.9%, respectively.

There is usually abundant corn stover available around an ethanol plant, which can also be used as a feedstock of the integrated CHP system for heat and power supply in the ethanol plant. As shown in Fig. 2, the feeding rate of corn stover with 20% moisture, on a wet basis, should be 27.6 tonne/h, which corresponds to 22.1 dry tonne/h, to meet the 66 MW_{th} processing heat and 6.8 MW_e power demands in the ethanol plant. In this case, the CHP system should include a 122.9 MW_{th} dryer, 122.9 MW_{th} gasifier, 16.4 MW_{th} hot syngas conditioner, 6.8 MW_e fuel cell and 131.1 MW_{th} combustor. About 3.33% of the energy stored in the corn stover was used to dry itself. The electricity output, thermal energy output and thermal energy input of the integrated CHP system were 6.8 MW_e, 66 MW_{th} and 122.9 MW_{th}, respectively. The electricity, thermal and total efficiencies of the CHP system were thus 5.5%, 53.7%, and 59.2%, respectively.

Although coal is not a renewable energy source, it has been consider as a cheap energy source to provide heat and power in an ethanol plant. Compared to biomass, coal is usually dry enough to be used as the feedstock of a CHP system directly. As shown in Fig. 3, the feeding rate of coal should be 14.5 tonne/h to meet the 66 MW_{th} processing heat and 6.8 MW_e power demands in the ethanol plant. In this case, the CHP system should include a 118 MW_{th} gasifier, 16.4 MW_{th} hot syngas conditioner, 6.8 MW_e fuel cell and 129.4 MW_{th} combustor. The electricity output, thermal energy output and thermal energy input of the integrated CHP system were 6.8 MW_e, 66 MW_{th} and 118 MW_{th}, respectively. The electricity, thermal and total efficiencies of the CHP system were thus 5.8%, 55.9%, and 61.7%, respectively.

3.3. Comparison of energy cost for ethanol production using different energy feedstocks

The capital cost and operating cost of the integrated CHP system with different feedstocks for heat and power supply in an ethanol

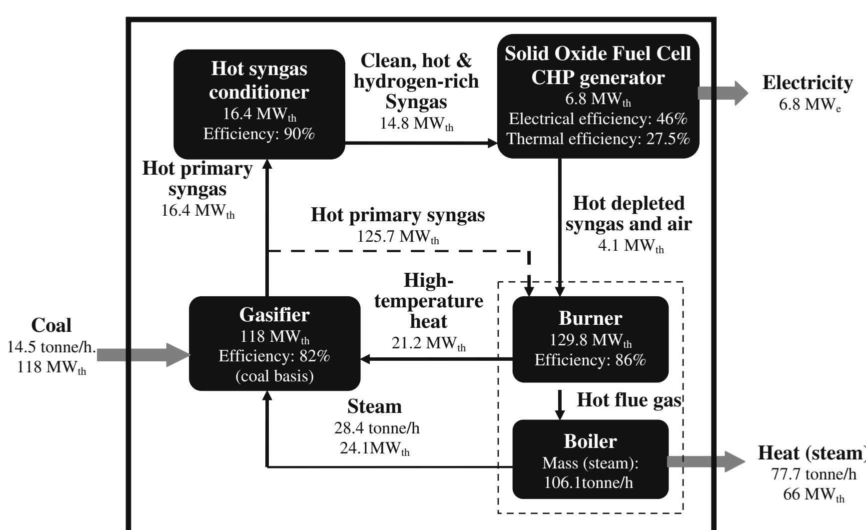

Fig. 3. Mass and energy flows of coal through an integrated fluidized bed gasifier and fuel cell CHP system for heat and power supply in a dry-grind ethanol plant with an annual production capacity of 189 million liters of ethanol.

plant with an annual production capacity of 189 million liters are given in Table 3.

The initial capital costs for the integrated CHP system with corn stover, DG and coal as feedstocks were 46.21, 40.67 and 30.32 million US$. Since DG is in a fine particle form and already in the ethanol plant, there is no need for additional grinding and storage units if DG is used as the feedstock of the CHP system. If coal is used as the feedstock, there is no need for a dryer. Most of dry-grind ethanol production facilities currently use natural gas to supply thermal energy and purchase electricity from commercial grids directly. For comparison, the energy cost in an ethanol plant using natural gas for processing heat and commercial grid for power was also calculated. If natural gas is used to supply heat in an ethanol plant, only a natural gas burner and steam boiler are needed. The capital cost for supplying heat and power with natural gas and commercial grid electricity was only 0.82 million US$, which was negligible, compared with the operating cost as given in Table 3. If the discount interest rate was 10% and the economical life of the CHP system was 15 years, the annual capital costs of the energy supplying facilities with corn stover, DG, coal, and natural gas and commercial electricity as energy sources were 6.51, 5.35, 3.99, and 0.11 million US$, respectively.

As given in Table 3, the annual operating costs of the CHP system using corn stover, DG and coal as its feedstock were 7.19, 13.76, and 5.12 million US$. The annual energy costs for the ethanol plant using the CHP system with corn stover, DG and coal as energy sources were thus 13.7, 19.11, and 9.11 million US$, respectively. The industrial price for natural gas and electricity were US$ 6.47/GJ (or US$ 7.86/cubic feet) and US$ 0.062/kWh in the United States in 2006 (Energy information administration, United States of America, online at http://tonto.eia.doe.gov). In this case, the predicted annual energy cost for the ethanol plant was 17.69 million US$, which was much higher than that of the CHP system with other energy resources of corn stover and coal, as electricity and natural gas are expensive energy sources.

The energy cost for ethanol production using natural gas for processing heat and commercial grid for power was predicted at 0.094 US$/l of ethanol, which matches well with the published data at 0.088 US$/l [28]. The integrated CHP system using coal as its feedstock achieved the lowest energy cost of 0.048 US$/l of ethanol, which was only about half of the cost of energy supply with natural gas and commercial grid. However, coal is not a renewable and environmentally-friendly energy source. If the renewable energy resources of corn stover and DG were used as the feedstock of the integrated CHP system, the energy costs for ethanol production were 0.070 US$/l and 0.101 US$/l, which would be 75% and 107% of the cost of heat and power supply with natural gas and commercial grid, respectively. Therefore, corn stover and DG are economically and environmentally favorable energy sources for supplying heat and power in an ethanol plant.

3.4. Effect of ethanol production scale on energy costs for ethanol production

Effect of the production scale of an ethanol plant on its production energy cost, using different energy feedstocks, are given in Fig. 4. For a given price of an energy feedstock, the energy costs for production of each liter of ethanol decreased slightly with an increase in the production scale if the integrated CHP system used corn stover, DG and coal as the feedstock. If the production scale was increased from 95 million liter/year (25 million gallon/year) to 379 million liter/year (100 million gallon/year), the energy costs decreased by 17%, 10%, and 18% for the ethanol production facility using the integrated CHP system with corn stover, DG and coal as the energy feedstock, respectively. However, there was no obvious change in energy cost with an increase in ethanol production scale for an ethanol production facility using natural gas and commercial grid electricity to supply heat and power. The production scale of an ethanol plant affects the scale of its utility system and thus the capital cost of the utility system. The capital cost of the integrated CHP system contributed to a significant percentage of the energy cost for ethanol production as given in Table 3. The capital cost of the integrated CHP system allocated to each liter of ethanol produced decreased with an increase in ethanol production scale. However, the capital cost of the heat and power system with natural gas and commercial grid electricity was negligible, while the

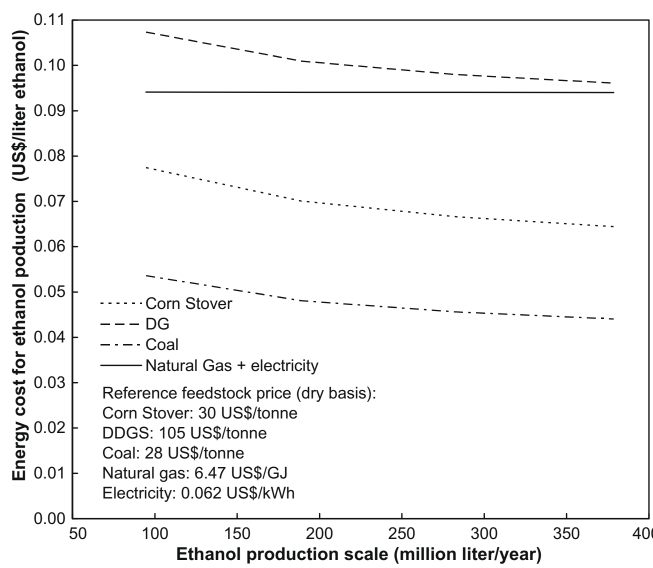

Fig. 4. Effect of ethanol production scale on energy cost for ethanol production in an ethanol plant using different energy feedstocks.

Table 3
Comparison of capital cost and operating cost for a CHP system for supplying heat and power from different feedstocks in a dry-grind ethanol plant with an annual production capacity of 189 million liters of ethanol.

Items of cost	Feedstock			
	Distiller's grains	Corn stover	Coal	Natural gas and electricity
Pretreatment unit cost (MUS$)	11.50	14.80	2.58	0
Gasification unit (MUS$)	5.23	5.69	5.53	0
Syngas cleaning (MUS$)	11.89	12.20	12.09	0
CHP unit (MUS$)	3.28	3.55	3.58	0.65
Installation cost (MUS$)	8.77	9.97	6.54	0.18
Total capital cost (MUS$)	40.67	46.21	30.32	0.82
Annual capital cost (MUS$/year	5.34	6.08	3.99	0.11
Annual operating costs (MUS$/year)	13.76	7.19	5.12	17.69
Production energy cost (US$/liter)	0.101	0.070	0.048	0.094

purchasing costs of natural gas and commercial power were a dominant contribution to the energy cost for ethanol production as shown in Table 3.

3.5. Effect of energy feedstock price on energy costs for ethanol production

The effect of energy feedstock price on energy cost for ethanol production is given in Fig. 5. For supplying heat and power with natural gas and commercial grid electricity in a dry-grid ethanol plant with an annual production capacity of 189 million gallons of ethanol, the energy cost for ethanol production was almost doubled if the prices of natural gas and electricity were doubled. If the integrated CHP system using corn stover, DG and coal as its feedstock for heat and power supply, the effect of energy feedstock price on energy cost for ethanol production became much smaller. If the prices of corn stover, DG and coal were doubled from 30, 105 and 28 US$/dry tonne to 60, 210 and 56 US$/dry tonne, the energy costs for ethanol production increased by 40%, 64%, and 35%, respectively. The energy cost for ethanol production consists of capital cost of the utility system and the operating cost. The cost of the energy feedstock is the main operating cost for ethanol production. Expensive energy feedstocks such as natural gas, commercial power and DG contribute a big percentage of the total energy cost for ethanol production. The more expensive an energy feedstock, the more significant the effect the feedstock price had on energy cost for ethanol production.

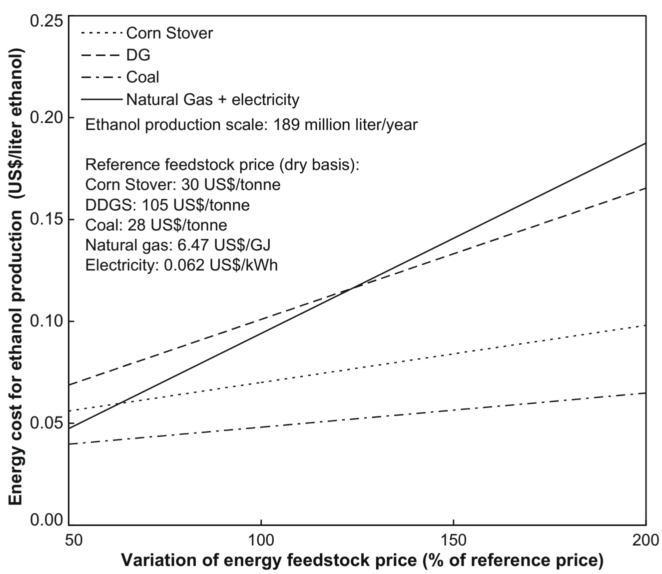

Fig. 5. Effect of energy feedstock price on energy cost for ethanol production in an ethanol plant with an annual production capacity of 189 million liters of ethanol.

It is worth noting that even if the price of corn stover was doubled from 30 US$/dry tonne to 60 US$/dry tonne and the prices of natural gas and commercial electricity were kept constant at 6.47 US$/GJ and 0.062 US$/kWh, the energy cost for ethanol production using the integrated CHP system with corn stover as the feedstock was 0.098 US$/l, which was still comparable to 0.094 US$/l for the energy cost of using natural gas and commercial grid electricity to supply heat and power as shown in Fig. 5.

3.6. Effects of moisture content of feedstock on the system performance and energy cost for ethanol production

The effects of moisture content of feedstock and thermal energy to electricity ratio of the integrated CHP system on its performance are given in Table 4. For a given thermal energy to electricity ratio, the electricity, thermal and total efficiencies of the integrated CHP system decreased with an increase in moisture content of the feedstock. At any given thermal energy to electricity ratio, if the moisture content of the feedstock increased from 10% to 70%, on a wet basis, all of the electricity, thermal and total energy efficiencies decreased by about 45.5%. If the moisture content of the feedstock was increased further from 70% to 80%, all of the electricity, thermal and total energy efficiencies decreased dramatically by an-

Table 4
Effects of thermal energy to electricity ratio and moisture content of corn stover on the performance of the integrated biomass gasifier and fuel cell CHP system for a dry-grind ethanol plant with an annual production capacity of 189 million liters of ethanol.

Thermal energy to electricity ratio	Moisture content of corn stover (%, wet basis)	Required amount of corn stover (MW_e)	Extra electricity (dry tonne/h)	Electricity efficiency of CHP system (%)	Thermal efficiency of CHP system (%)	Total energy efficiency of CHP system (%)
0.5	10	76.3	125	31.1	15.6	46.7
	20	78.6		30.2	15.1	45.3
	30	81.7		29.1	14.5	43.6
	40	86.2		27.6	13.8	41.4
	50	93.4		25.4	12.7	38.2
	60	106.7		22.3	11.1	33.4
	70	140.2		16.9	8.5	25.4
	80	376.5		6.3	3.2	9.5
1	10	47.4	59	25.0	25.0	50.1
	20	48.8		24.3	24.3	48.7
	30	50.7		23.4	23.4	46.8
	40	53.5		22.2	22.2	44.4
	50	58.0		20.5	20.5	41.0
	60	66.3		17.9	17.9	35.8
	70	87.1		13.6	13.6	27.3
	80	233.9		5.1	5.1	10.2
9.7	10	21.5	0	5.7	55.3	61.0
	20	22.1		5.5	53.7	59.2
	30	23.0		5.3	51.7	57.0
	40	24.2		5.1	49.0	54.0
	50	26.3		4.7	45.2	49.9
	60	30.0		4.1	39.5	43.6
	70	39.5		3.1	30.1	33.2
	80	106.0		1.2	11.2	12.4

other 62.5%. More moisture in the feedstock requires more energy to dry the feedstock. It requires about 53%, 31% and 1.5% of the energy resided in the dry mass of the feedstock with moisture contents of 80%, 70%, and 10% on a wet basis, to remove its moisture, respectively. Therefore, in terms of energy efficiency of the integrated CHP system, the moisture content of the feedstock going into the integrated CHP should be lower than 70% on a wet basis. The moisture content of most naturally-dried biomass feedstocks is usually between 15% and 30% [29].

An increase in the moisture content of biomass feedstock will increase both the capital cost and operating cost of the integrated CHP system due to drying of the biomass. Effect of moisture content of feedstock on energy cost for ethanol production in a dry-grind ethanol plant with annual production capacity of 189 million liters of ethanol is given in Fig. 6. At a given thermal energy to electricity ratio, the energy cost for ethanol production increased with an increase in the moisture content of the feedstock. As shown in Fig. 6, there was a dramatic increase in energy cost for ethanol production if the moisture content of the biomass feedstock was higher than ~70%, on a wet basis. At the thermal energy to electricity ratio of 9.7, the energy cost for ethanol production increased from 0.069 US$/l to 0.109 US$/l if the moisture content of the corn stover increased from 10% to 70%, on a wet basis. If the moisture content of the corn stover was 80%, the energy cost for ethanol production became 0.248 US$/l, which was much higher than the energy cost of 0.094 US$/l using natural gas at a price of 6.47 US$/GJ and commercial grid electricity at a price of 0.062 US$/kWh to supply heat and power. In terms of energy cost for ethanol production, the moisture content of the feedstock into the integrated CHP also should be lower than 70%, on a wet basis.

3.7. Effects of thermal energy to electricity output ratio of the integrated CHP system on the system performance and energy cost for ethanol production

To meet the heat and power demand at a ratio of 9.7 in an ethanol plant with an annual production capacity of 189 million liters of ethanol, the integrated CHP system required 22.1 dry tonnes of corn stover with 20% moisture, on a wet basis, per hour. In this case, the electricity, thermal and total energy efficiencies were 5.5%, 53.7%, and 59.2%, respectively as given in Table 4. To decrease the thermal energy to electricity ratio of the integrated CHP system, extra electricity should be generated for the given demand of thermal energy in the ethanol plant. As shown in Table 4, for a biomass feedstock with a given amount of moisture, the electricity efficiency of the integrated CHP system increased with a decrease in the thermal energy to electricity ratio while the thermal and total energy efficiencies decreased with a decrease in the ratio. For corn stover with 20% of moisture, on a wet basis, the electricity efficiency of the integrated CHP system increased from 5.5% to 30.2% if the thermal energy to electricity ratio decreased from 9.7 to 0.5 while the thermal and total energy efficiencies were decreased from 53.7% to 15.1%, and from 59.2% to 45.3%, respectively. At the ratio of 0.5, the integrated CHP is used mainly for electricity generation rather than supplying processing heat.

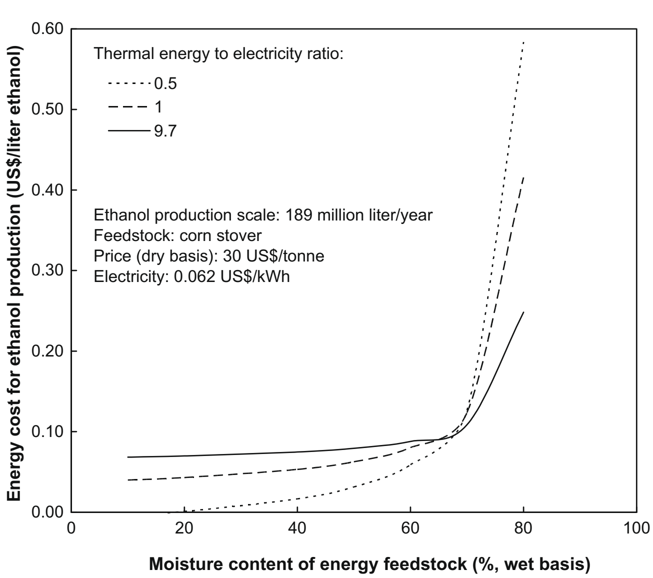

Fig. 6. Effects of thermal energy to electricity ratio of the CHP system and moisture content of energy feedstock on energy cost for ethanol production in an ethanol plant with an annual production capacity of 189 million liters of ethanol using corn stover as an energy feedstock.

Although the demand ratio of thermal energy to electricity in a dry-grind ethanol plants is around 9.7, the extra electricity generated by the integrated CHP system may be sold to the public grid to add revenue to the ethanol plant and, thus, decrease the net energy cost for ethanol production. A decrease in the thermal energy to electricity ratio increases both the capital cost of the CHP system and the revenue of extra electricity. As shown in Fig. 6, when the moisture content of the corn stover was less than 70%, on a wet basis, there was significant decrease in energy cost for ethanol production if the thermal energy to electricity ratio decreased from the demand value of 9.7–0.5. If the extra electricity generated by the integrated CHP system could be sold at 0.062 US$/kWh and corn stover price with 20% moisture, on a wet basis, was 30 US$/dry tonne, the energy cost for ethanol production was only 0.001 US$/l at the ratio of 0.5, compared to 0.07 US$/l at the ratio of 9.7. Therefore, there is a significant economical potential to integrate a CHP plant with an ethanol plant. However, it is worth noting that a large amount of energy feedstock is required to decrease the thermal energy to electricity ratio of the CHP system for increased extra electricity generation. At a thermal energy to electricity ratio of 0.5, the extra electricity generated by the integrated CHP system was 125 MW_e and the required corn stover was 78.6 dry tonne/h given in Table 4. The availability and price of the feedstock could restrict a decrease in the thermal energy to electricity ratio.

4. Conclusions

The technical and economical feasibility of an integrated biomass gasification and fuel cell CHP system was analyzed for supplying the heat and power in an ethanol plant. The energy cost for ethanol production using natural gas at a price of 6.47 US$/GJ for processing heat and the commercial grid electricity at a price of 0.062 US$/kWh for power supply in a dry-grind ethanol plant with an annual production capacity of 189 million liters of ethanol was as high as 0.094 US$/l ethanol. If the integrated CHP system with DG with 64.7% moisture, on a wet basis, at 105 US$/dry tonne and corn stover with 20% moisture, on a wet basis, at 30 US$/dry tonne as feedstock was used to supply heat and power in the ethanol plant, the energy costs for ethanol production were 0.101 US$/l and 0.070 US$/liter, which were 107% and 75% of the cost of supplying heat and power with natural gas and commercial grid electricity, respectively. To meet the demand of processing heat and power in the ethanol plant, the integrated CHP system required 22.1 dry tonnes of corn stover per hour or 14.5 dry tonnes of DG per hour, compared with 18.8 dry tonnes of DG per hour available in the ethanol plant.

The energy costs for ethanol production decreased slightly with an increase in the ethanol production scale using the integrated CHP system with corn stover and DG as the feedstock for supplying heat and power. The production scale had no significant effect on the energy cost for ethanol production with natural gas and commercial grid electricity. If the prices of DG and corn stover were doubled, the energy costs for ethanol production would increase by 64% and 40%, respectively. If the prices of natural gas and electricity were doubled, the energy cost for ethanol production was almost doubled. The increase of feedstock moisture decreased the electricity, thermal and total efficiencies, and increased the energy cost for ethanol production. In terms of energy efficiency of the integrated CHP system and energy cost for ethanol production, the moisture content of the feedstock going into the integrated CHP should be lower than 70%, on a wet basis. A decrease in the thermal energy to electricity ratio increased the electricity efficiency of the integrated CHP system but decreased the thermal and total efficiencies of the system. If the moisture content of the corn stover was less than 70%, on a wet basis, and the thermal energy to electricity ratio decreased from the demand value of 9.7–0.5, there was a significant decrease in energy cost for ethanol production.

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